2. ENVIRONMENTAL STUDY

2.1 GENERAL

The environmental impact assessment survey was carried out during the Phase I Study (1998-2000). The survey results shown below are quoted from Outline of the Study in Final Report, Vol.2: Executive Summary. Accordingly, every survey items were assessed between the large-scale alternative (FSL.360m) and the medium-scale alternative (FSL.320m).

Meanwhile during the Phase II study, the field survey of resettlement potential area was carried out in July 2002 for the resettlers of four (4) villages in case of the medium-scale alternative (FSL.320m). The summary of survey results is attached to the end of this chapter.

2.2 EXECUTION OF WORKSHOPS

The workshops were held during both the Phase I Study and the Phase II Study. The Study has been affected by the workshops.

The Phase I Study (July 1998 to March 2000)

No.	Workshop	Date	Place	Agenda	Participants
1.	1st General Workshop	November 1998	Vientiane	Inception Report	110
2.	2nd General Workshop	June 1999	Pakxan	Interim Report	120
3.	3rd General Workshop	December 1999	Vientiane	D/Final Report	120
4.	1st Site Workshop	March 1999	Don/Sopyouk/Muanmai	Inception Report	50, 30
5.	2nd Site Workshop	June 1999	Don/Sopyouk/Muanmai	Interim Report	40
6.	3rd Site Workshop	December 1999	Don/Sopyouk/Muanmai	D/Final Report	200, 170, 70

The Phase II Study (March 2001 to November 2002)

No.	Workshop	Date	Place	Agenda	Participants
1.	1st General Workshop	June 2001	Vientiane	Inception Report	110
2.	2nd General Workshop	March 2002	Pakxan	Interim Report	100
3.	3rd General Workshop	September 2002	Vientiane	D/Final Report	130
4.	1st Site Workshop	June 2001	Don/Sopyouk/Muanmai	Inception Report	No Record
5.	2nd Site Workshop	March 2002	Don/Sopyouk/Muanmai	Interim Report	50, 40, 100
6.	3rd Site Workshop	September 2002	Sopyouk	D/Final Report	40

2.3 ENVIRONMENTAL IMPACT ASSESSMENT

IMPACTS IN THE DOWNSTREAM AREA

Both the proposed FSL alternatives EL.360m and EL.320m have the same dam site. Consequently, the environmental impacts in the downstream area are very similar and do not provide a significant basis for differentiating the two (2) alternatives from the environmental point of view.

RESERVOIR AREA AND FOREST

The large-scale dam alternative (FSL.360m) will inundate exactly not only twice more land (14,820ha) than the medium-scale alternative (FSL.320m, 7,390ha), but also three (3) times more cultivated land (950ha compared to 310ha). Almost 10,000ha of forest, representing a potential timber volume of 290,000m3 are also flooded by FSL.360m, against only half of these values for FSL.320m.

WATER QUALITY IN THE RESERVOIR

The clearing of reservoir is efficient to reduce the duration of low water quality. However, the clearing of the forest in the vast Nam Ngiep reservoir of 74km2 may require an immeasurable long time and huge cost. Therefore, it seems not economical and realistic.

The improvement of the low-water quality at the downstream river stretch will have to be planned with some re-aeration facilities.

SEQUESTERING LOSS OF CARBON

With the flooding of the forest, Laos will lost a potential for sequestering the carbon, resulting eventually in a higher contribution to global warming. It represents a loss for a potential selling of carbon credits to any industrialized nations. Based on a forest growth of 2 to 3 m3/ha/year, the loss may be estimated at US$180,000-270,000/year for FSL.360m and at US$88,000-130,000/year for FSL.320m.

DRAW-DOWN AREA CULTIVATION

During operation, the water level of the reservoir will fluctuate, exposing draw-down areas which may be developed for agriculture or grazing. For rice production, the land must be exposed around 5 months. FSL.320m offers almost twice more areas for rice cultivation than FSL.360m: almost 2,000ha against 1,000ha. Only a part of this area is suitable for rice culture when considering soil quality and local topography.

WATER QUALITY IN MEDIUM AND LONG TERM

The residence time of water into the reservoir is about 13 months for FSL.360m and only 3.6 months for FSL.320m. This short residence time combined with a limited inflow of Phosphorus from the watershed leads to the conclusion that there should be no problem of water quality in the medium and long term. After the impoundment, as the intense decay of organic matter in the water consume all the dissolved oxygen, it is anticipated that the water will recover a reasonable level of oxygen after only 5 to 6 years for FSL.360m and after only 2 years for FSL.320m.

WATER QUALITY IN SHORT TERM

Because of its depth, the reservoir will probably be stratified, with a 15-20m depth layer of well aerated water over a deeper water body of colder and anoxic water. Turn over may occur during the cold season as observed in the Nam Ngum reservoir, but its magnitude has still to be assessed. As the water intake is located most of the year below 20m from the surface, it is anticipated a release of low quality water in the downstream river, with impacts on aquatic life and population. To mitigate this impact, appropriate facilities as multi level intake or downstream re-aeration structure may be studied in a further investigation.

RE-REGULATION FOR DOWNSTREAM

A re-regulation facility will be constructed below the tailrace channel to regulate the flow over 24 hours, to avoid daily changes in river flow which could have resulted in hazards for the population and excessive erosion of the riverbed.

The average monthly flow will be significantly changed at the downstream area: the dry season flow will be increased 3 times and the wet season flow reduced by 50% from present situation.

IMPACTS OF ACCESS ROAD AND TRANSMISSION LINE

Impacts on land at downstream will be limited to land acquisition for only 10km of access road and 110km of transmission line. Compensation for the loss of land will be provided to the concerned population. Impact is the same for both alternatives.

ENVIRONMENTAL MANAGEMENT PLAN

To mitigate the impacts during construction, filling stage of the reservoir and operation stages, a program of activity has been prepared in the Environmental Management Plan (EMP). The constitution of an Environmental Management Unit (EMU) is also proposed.

2.4 PRELIMINARY RESETTLEMENT PLAN

POSSIBLE INVOLUNTARY RESETTLEMENT

According to the socioeconomic surveys of the Project area conducted December 1998 through March 1999, overall, including both Upstream and Downstream areas of the proposed dam site, nearly 2,000 households and 12,000 persons may be affected to one degree or another by the Project. About 660 households and 5,000 persons in 14 villages are in the Upper Reservoir and another 200 households and 1,200 persons in 4 villages the Lower Reservoir could potentially be affected by involuntary resettlement. For Downstream area about 1,300 households and 6,800 people in 15 villages would be *affected through changes in the Nam Ngiep River flow and water.*

FSL.360M ALTERNATIVE

While not all villages within the proposed reservoir area would be submerged even by FSL.360m, their rice lands are all situated along the Nam Ngiep River and its territories at low levels. So it can be assumed that virtually all the villages would require resettlement, if FSL.360m is chosen for implementation. Generally speaking, mitigation includes minimizing resettlement to the extent possible, carrying out an international standard of resettlement planning and implementation if unavoidable, and fair compensation for the displaced population.

FSL.320M ALTERNATIVE

The recommended design mitigation at this time is to consider the medium-scale dam alternative. The initial thinking was that lowering the FSL to EL 320m would reduce the number of affected villages down to 5 villages. There is not enough information at this time, however, to determine what the amount of backwater effect would be, i.e., how much higher the water at the back of the reservoir will be than at the front end. Two (2) meters would be assumed, including a safety margin. Therefore, consideration of the backwater effect indicates that EL.318m might be necessary to protect the majority of irrigated paddy land belonging to the Upper Reservoir villages, nearly 300ha of the total reservoir paddy land. This FSL.318m dam would more surely reduce the affected population down to 260 households and about 1,600 people.

Note; The paragraphs above are quoted from the Phase I Final Report as mentioned in Chapter 6.1 General hereof. In the paragraph above, the FSL.318m, which is 2m below the proposed FSL.320m, was recommended, however, FSL.320m has been applied to the final design by the limited maximum sedimentation height at EL.320m due to the Phase II study results as shown in Chapter 8.3.2 Backwater Effect, hereinafter.

PREPARATION OF FULL RESETTLEMENT ACTION PLAN

The Preliminary Resettlement Plan (PRP) is prepared without the final design of the Project having been decided. Once the alternative is selected, a full Environmental Impact Assessment (EIA) and Social Impact Assessment (SIA) will be required by internationally accepted guidelines, as well as preparation of a full Resettlement Action Plan (RAP) and a Social Action Plan (SAP) for mitigating other social impacts. During preparation of a draft RAP, the following studies will take place:

(i) Socio-Cultural Assessment of Resettlement and Host Communities (Part of SIA),

(ii) Preparation of a Public Consultation Framework,

(iii) Capacity Assessment of Resettlement Sites,

(iv) Backwater and Sedimentation Modeling,

(v) Archeological Review and Field Survey, and

(vi) Technical Resources explored and detailed TOR for development of Livelihood Packages prepared.

RESETTLEMENT POTENTIAL AREA SURVEY PHASE II STUDY (IN 2002)

The objective of the resettlement site study is to conduct a detailed survey in the resettlement potential areas. The field survey was conducted by confirming suitability for two (2) resettlement areas and a small possible area just downstream of the proposed dam site. All potential sites are located in Bolikhanh District of Bolikhamsay Province as shown in Figure 2.2 and the following table:

1.	Name of Area	Xiengxian-XiengLeu and Hatkham	Phabuak
2.	Location	a flat terrain along the Nam Lat river stretched from B.Thasi to B.XiengLeu, about 54km from the Bolikhanh district.	a flat terrain located between Talabat and Pousiat mountains along the Nam Sun and Nam Poy rivers around at B.Pakbuak, distance about 37km from the Bolikhanh district.
3.	Surrounding	The North : Nam Mang river The East : Thathom district, Xaisomboun The South : Viengthong district The West : Pou Had and Pou Phathao mountains	The North : Nam Sun river The East : Pou siet mountain The South :Pou Meuy mountain The west : Talabat mountain
4.	altitude	from EL188 to EL.210	-

The objective of the resettlement area survey at Phase II Study was to verify the suitability of the potential areas through a field survey to be undertaken with the participation of the representatives of local communities.

The field survey report includes survey results on (i) land use and forest cover, (ii) land suitability for rice cultivation and other crops, (iii) soil type, (iv) irrigation possibility, (v) land suitability for livestock, (vi) water source availability for domestic consumption, (vii) accessibility, (viii) electrification possibility. And surveyors collected (i) opinion of the local authorities and communities regarding each potential site, and (ii) photography of main physical features of each site.

The survey team briefed the local authority and community on the scope of the survey prior to field visit. The survey team collected their opinions on the relevance of each potential site after the field visit. Soil survey was carried out on the basis of the visual observation and the soil sampling for laboratory analysis (nutrient content, texture and salinity). Types of land use were identified based on existing maps, aerial photo interpretation and field check. GPS was used for assessing the size of the potential site. Irrigation potential was assessed through the visit of streams near each potential site and empirical computation of the water availability.

A Resettlement Site Survey was initiated in July and August, 2002 and was undertaken by STS Consultants, a local consulting firm. This survey focused on sites in Bolikhan District of Bolikhamsay Province, evaluated the topography, present land use, soils, land suitability for rice culture and other crops and considered local water resources, road access, infrastructure and electricity sources. The three (3) sites surveyed included

(i) Thaksi- Xieng Leu- Xieng Xiane – approximately 2,367 ha containing seven (7) villages with a total population of 2,158 persons located along the future Highway 1D

(ii) Pakbuak – approximately 3,924 ha containing four villages with a total population of 1,480 persons and located with future access roads gazetted for completion prior to 2005.

(iii) Hatkham – approximately 385 ha with no resident villages some evidence of use on a seasonal basis and located on the West bank of the Nam Ngiep River in the vicinity of the re-regulation weir with no access at present.

The locations of the sites are given in Figure 6.3.5 and all show good potential for agricultural development when irrigation is developed. The planning for development of the first two (2) sites is being assisted by the Lao-Luxemborg Land Use Planning Project.

No consideration was given to resettlement sites located within Hom District. The full results of the survey are contained in "Detail Report on Resettlement Survey – Nam Ngiep 1 Hydroelectric Power Project" by STS Consultants (August, 2002). The comparison results are shown below:

	items	Score	Resettlement Site		
			Thasi-Xiengxiane	Phakbuak	Hatikham
Existing Communities					
1.	- Number of Villages		7	4	0
2.	- Total Population		478 Families	341 Families	0 Families
3.	- Cultural Affinities		30% Lao Lum & 70% Lao Theung	11% Lao Lum & 89% L. Theung	Lao Lum & Lao Soung
4.	- No. of Schools & Teachers		7 and 20	4 and 14	1 and 7
5.	- No. of Health Posts		0	1	0
Site Investigations					
1.	- Total Area - ha		2367	3924	385
2.	- Existing Land Use - ha				
	Irrigated Land		133	30	0
	Rainfed Paddy		449	75	5
	Shift Cultivat & Other		132	150	137
3.	- Total Area per Family -ha		1.5	0.7	Unknown
4.	- Capacity @ 1.5 ha/ Family		1102 Families	2446 Families	165 Families
5.	- Slope				
	< 8%		74%	83%	100%
	>8% and < 16%		26%	17%	-
6.	- Irrigation Area/ Potentials				
	Built or Programmed		30 ha	0 ha	0 ha
	Proposed/ Potential		6 Projects- 3120 ha	Nam Sun-2000 ha	River –63 ha
7.	- Suitability-Rice Cultivation				
	LSR 1 Class – ha		435	1086	385
	LSR 2 Class – ha		1223	670	-
	LSR 3 & 4 Class - ha		709	2166	-
8.	- Accessibility Potential				
	National Roads		Hwy 1D	-	Paved Road
	Provincial Roads		Road 01	Road 01	-
	District/ Local Roads		Yes	Limited	No
9.	- Electricity Potential				
	Access to Pakxan 22kV		Yes	Yes	Yes
	Local Mini-hydro		N.Mang – 4.8 Mw	No	No
	Local Project Grid		No	No	Yes
Based on Site Investigations		Score			
1.	- Land Availability	10	8	10	4
2.	- Irrigation Potential	25	25	20	15
3.	- Soil Suitable for Rice	20	15	18	14
4.	- Avail of Electricity	10	8	6	8
5.	- Avail of Resources	10	7	10	8
6.	- Availability of Water	5	5	5	3
7.	- Availability of Access	10	9	7	9
8.	- Cap @ 1.5 ha/ Family	10	7	10	6
	Total for Evaluation	100	**84**	**86**	**67**
	Ranking of 3 Options		**2nd**	**1st**	**3rd**
	Evaluated Points		Favorable from Irrigation and Access Viewpoint	Favorable from Large Capacity and Resources	Keep for Works Resettlement

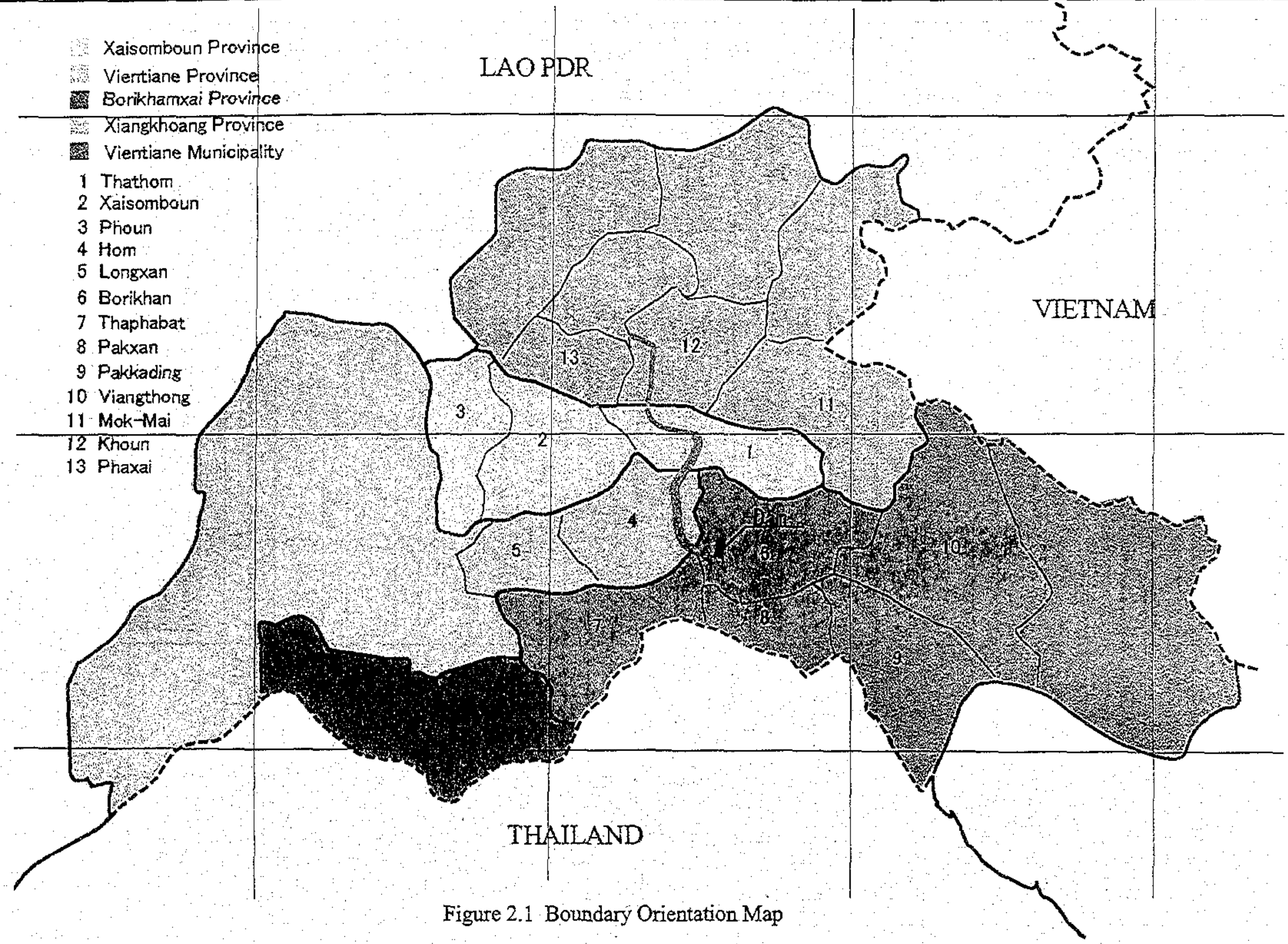


Figure 2.1 Boundary Orientation Map

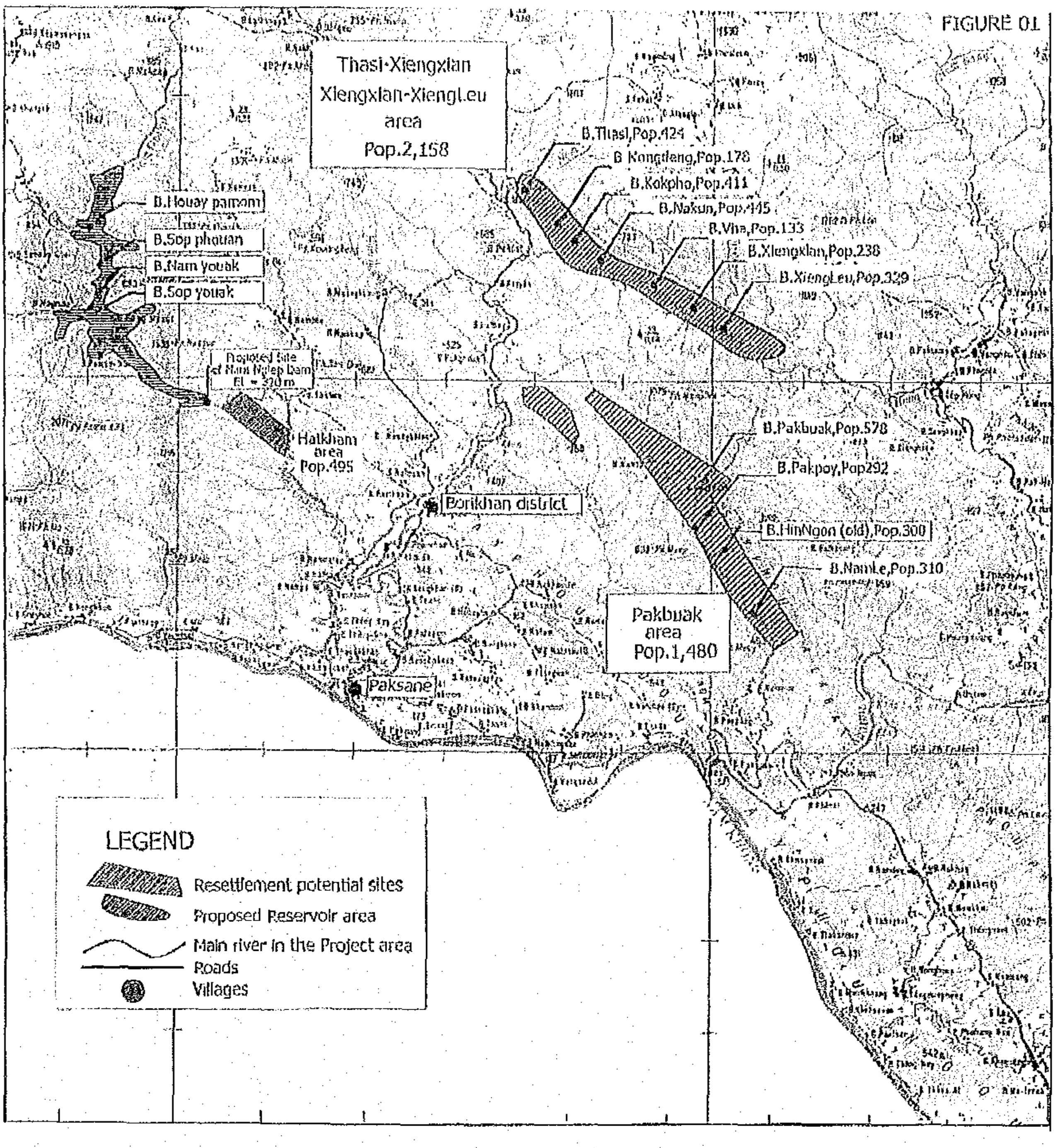


Figure 2.2 Potential Resettlement Sites (Phase II Study)

3. POWER MARKET RESEARCH

3.1 OVERVIEW OF LOA PDR MACROECONOMY AND ROLE OF POWER SECTOR

The gross domestic product (GDP) of Lao PDR has continued to grow after a slowdown in 1998 due to the 1997 currency crisis. The real GDP growth rate was 7.3% in 1999 and 5.9% in 2000. Growth in the agricultural sector has been healthy at 8.2% in 1999 and 5.1% in 2000, and growth is balanced among the sectors. Agriculture led the recovery in 1999, and industry and energy production (largely for export) were major contributors to growth in 1999 and especially in 2000. External conditions permitting, the country should be able to grow by 6 to 7% in the next two years.

Exports have grown steadily since 1998 and the balance of payments, although in deficit, is improving. Major exports include wood products, electricity and textiles. External financing has been the major source of funding for the balance of payment deficit, although foreign direct investment (especially in the hydroelectric sector) has played an important role as well. This trend is expected to continue as new hydroelectric investments enter the country.

The power sector has played a pivotal role in the economic development of Lao PDR over the last thirty years. Continued economic growth is needed to alleviate poverty and achieve social development goals but the policy options for achieving this are constrained by the small domestic economy and limited trade opportunities. At the current stage of development, Lao PDR has only a few industries in which it enjoys a comparative advantage in the region: the most important of these is the generation of electricity. The country has large and untapped energy reserves, principally hydropower and lignite, and a central location in a region characterized by expanding electricity demand.

The Lao power sector is, however, still in a very early stage of development despite of huge potential: only 625 MW (3.5%) of an estimated 18,000 MW of exploitable hydropower potential has been harnessed and the existing power grid serves only 30% of the national population. The sector is expected to play a pivotal role in achieving the social and economic development objectives of GOL by expanding the availability of stable and reliable electricity supply within the country and earning foreign exchange by exporting electricity.

The electricity export has been one of few major foreign currency earning industries since 1972 when Nam Ngum 1 HEPP started to export power to Thailand. The export of electricity is a major contributor to steady export growth, which increased from US$30 million (19.6% of total export value) in 1996 to US$112 million (28.5% thereof) in 2000. This is reflected in the GOL's GOL's power sector policy which aims to promote power generation for export to provide foreign currency revenue to meet GOL development objectives.

3.2 POWER MARKET OVERVIEW IN GMS COUNTRIES

The Greater Mekong Sub-Region (GMS) countries includes Cambodia, Lao PDR, Myanmar, Thailand, Vietnam and the Yunnan Province of the PRL. The principal electricity markets for export of power from Laos for next 10-20 years are Thailand and, to a lesser extent, Vietnam. The other neighboring countries are unlikely to have import needs for power from Laos during the next decade, except possibly for supplies on a small scale to Cambodia in the border area.

The following table summarizes the estimated electricity load growth in the GMS countries, as obtained from recent projections:

Country	Peak Demand, MW			Energy, GWh/a		
	2000	2005	2010	2000	2005	2010
Thailand(PDP 2001)	14,918	21,222	28,912	96,781	134,794	184,213
Vietnam	4,487	7,802	11,653	26,000	46,459	70,437
Yunnan, China	3,371	4,715	6,362	21,857	30,569	41,241
Myanmar	1,125	1,628	2,124	6,905	9,627	12,094
Lao PDR	**172**	**321**	**464**	**649**	**1,527**	**1,963**
Cambodia	150	304	477	678	1,200	1,900

The Government of Thailand and the Government of Lao PDR (GOL) had entered into two Memorandum of Understanding (MOU), dated June 4, 1993 and June 19, 1996 expressing their intention to cooperate on the development of 3,000 MW of electric power in Lao PDR for sale to Thailand by the year 2006.

The GOL reached an MOU with the Government of Vietnam to supply 1,500 to 2,000 MW by the year 2010. Subsequently specific discussions were held concerning power purchase agreements in July 1998 and in March 1999. According to the most recent information, planned purchases by Vietnam from Lao PDR will be 1,000 MW between 2005 and 2010; and 1,000 MW between 2010 and 2015.

3.3 POWER SECTOR DEVELOPMENT IN LAO PDR

The GOL has attached high priority to hydropower expansion in pursuit of its macroeconomic and social objectives. The power sector policy calls for the development of power projects at two levels to meet the different market requirements:

(i) **Domestic Generation Projects:** The primary purpose of domestic projects is to supply the national market. EDL builds and operates these plants with concessionary finance and their availability of capital usually limits their size to around 100 MW.

(ii) **Export Generation Projects:** Export projects are primarily implemented by IPP groups specifically to meet commitments under the inter-governmental MOUs. The projects are large, generally in excess of 100 MW.

As mentioned above, the GOL has signed with the Government of Thailand to commit 1,600 MW of power capacity by the year 2006 and 1,700 MW by 2008, and reached an MOU with the Government of Vietnam to supply 1,500 to 2,000 MW by the year 2010. The GOL's plan is to expand the installed capacity to over 3,000 MW, most of which will be implemented by IPP projects and dedicated to export.

Out them two projects (Theun Hinboun and Houay Ho) are under operation. Currently the following six projects have been already committed in the Thai-Lao power purchase program.

First Stage Scheduled COD in Dec. 2006	Second Stage Scheduled COD in Mar. 2008
Nam Theun 2	Hongsa Lignite
Nam Ngum 2	Xe Pian-Xe Namnoy
Nam Ngum 3	Xe Kaman 1

The progress of these six project development has not met expectations. As such the GOL is currently reviewing the status and problems of each project by way of questionnaire survey. By this study the sequence of the projects for export will be reassessed and Thai-Lao power purchase program will be updated and revised if necessary.

To meet the future power demand for domestic use and export market MIH/EDL has prepared a latest power development plan as of March 2002. The following table shows candidate projects for export purpose:

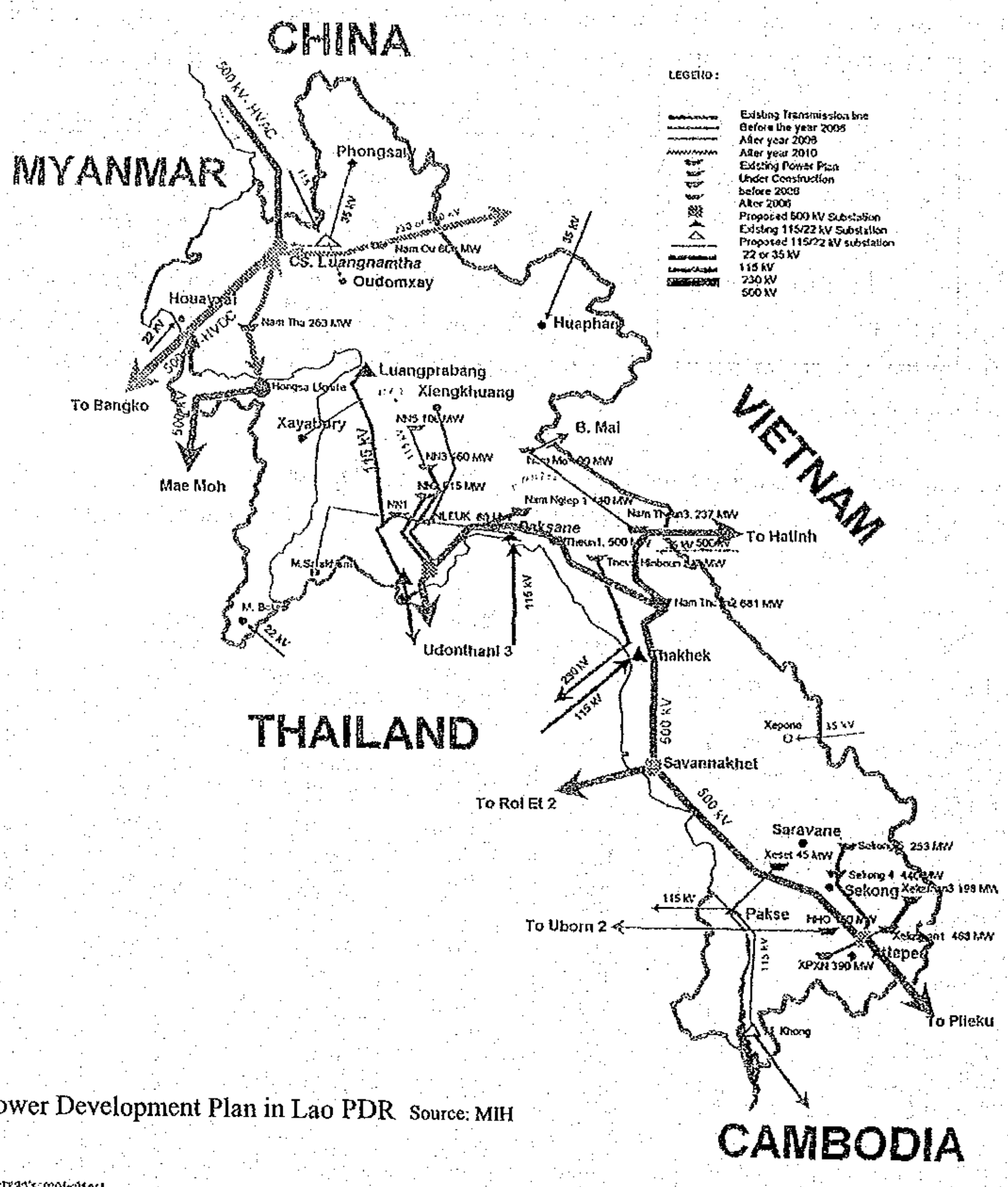
Plant (Power Region)		Capacity (MW)	Year of Commission	Export to	Power to Domestic	Energy to Domestic
Nam Mo	(Central 1)	105	2007	Vietnam	5 MW	29 GWh
Nam Ngum 2	(Central 1)	615	2008	Thailand	31 MW	105 GWh
Nam Ngum 3	(Central 1)	460	2008	Thailand	23 MW	93 GWh
Nam Theun 2	(Central 1)	1,088	2008	Thailand	75 MW	275 GWh
Hongsa Lignite	(Northern)	720	2010	Thailand	36 MW	213 GWh
Xe Pian-Xe Namnoy	(South)	390	2010	Thailand	20 MW	100 GWh
Xe Kaman 1	(Southern)	468	2010	Thailand	23 MW	96 GWh
Nam Theun 1	(Central 1)	400	2014	Vietnam	20 MW	95 GWh
Nam Kong 1	(Southern)	240	2012	Vietnam	12 MW	40 Gwh
Xe Kaman 3	(Soutehrn)	218	2012	Vietnam	11 MW	67 GWh
Nam Ngiep 1	(Central 1)	240	2011	Thailand	12 MW	71 GWh
Sekong 4	(Southern)	440	2014	Vietnam	22 MW	87 GWh
Sekong 5	(Southern)	253	2014	Vietnam	13 MW	59 GWh
Nam Theun 3	(Central 1)	236	2016	Vietnam	12 MW	39 GWh
Nam Ngiep 2	(Central 2)	495	2016	Thailand	25 MW	124 GWh
Nam Ou	(Northern)	500	2018	Thailand	25 MW	131 GWh
Nam Khan 2	(Northern)	145	2018	Thailand	7 MW	36 GWh
Total		7,013	-	-	372 MW	1,660 GWh

Note : 1. Peak power and energy for domestic supply are estimated at 5% of total production of each power plant.
2. Locations of proposed power plants are shown in Figure 7.3.1
Source: System Planning Office of EDL

According to the program Nam Ngiep-I HEPP is expected to be commissioned in year 2011 with a capacity of 240 MW. Out of this capacity 12 MW will be allocated for domestic use.

As for the future transmission network for export power from Lao PDR, there are various plans being studied by MIH and EDL. Those plans were summarized as shown in the following figure as the future national grid of Lao PDR:

POWER DEVELOPMENT PLAN



Power Development Plan in Lao PDR Source: MIH

3.4 EXPORT POTENTIAL TO THAILAND

In October 2001 EGAT prepared its most recent long-term power development plan (PDP 2001) which applies to the years 2001 through 2016 (see Table 3.1). According to this plan, the EGAT will add a total 33,077 MW in new capacity by the end of September 2016 at the end of its 11th five year economic development plan (see Table 3.2).

The total installed capacity of projects that will be developed during the ninth five year plan (2002–2006) is 5,091 Ml of which 1,147 MW will be developed by EGAT, and the remaining 3,944 MW is scheduled to be procured from domestic IPPs.

During the 10th five year plan (2007–2011) new development of 11,976 MW will be required. EGAT plans to develop 2,893 MW, and procure 3,283 MW from Laos, while the remaining 5,800 MW in power will be purchased from domestic IPPs and neighboring countries (including Laos). The details of the 3,283 MW in commitments made by Laos consist of 1,903 MW from Nam Theun 2, Nam Ngum 3, and Nam Ngum 2 for which purchases are projected by September 2007; and a total of 1,380 MW from Hongsa Lignite, Xe Kaman 1 and Xe Pian-Xe Namnoi for which purchases are projected through March 2008. There is a projected need for new power of more than 2,000 MW per year around 2011 when Nam Ngiep-I HEPP is scheduled to come on line, and consequently market demand for Nam Ngiep will be substantial, which means that the project will be highly feasible if it is price competitive.

During the 11th five year plan (2012–2016), development of 13,160 MW is projected to occur. EGAT has only one site to develop a 660 MW pumped storage project and plans to purchase the remaining 12,500 MW from domestic IPPs and SPPs, as well as neighboring countries.

Consequently ten years from now the Thai power market will rely for its supply on domestic IPPs and purchases of power from neighboring regions, and is likely to have a freely competitive market based on the pooling of power, with many power companies entering the market as they seek to find hungry markets for power.

Nam Ngiep-I HEPP is expected to cope with peaks or intermediate peaks in the load curve. A screening curve analysis has been conducted for the purpose of finding the plant factor rate at which Nam Ngiep-I HEPP can maintain price competitiveness with competing power sources. The analysis has recommended a plant factor rate of at least 50% and operation of at least 12 hours per day would be desirable for Nam Ngiep-I HEPP. If utilization falls below this level, combined cycle generation would have the advantage.

Figure 3.1 presents the daily load curve for 2011 when Nam Ngiep-I HEPP is scheduled to be commissioned. This diagram indicates the desired position of Nam Ngiep-I HEPP. Under the proposal for 240 MW, the plant would be a marginal producer accounting for only 0.8% of the peak demand of 30,587 MW, but Nam Ngiep-I HEPP is still expected to have an important role as an intermediate plant during peak demand.

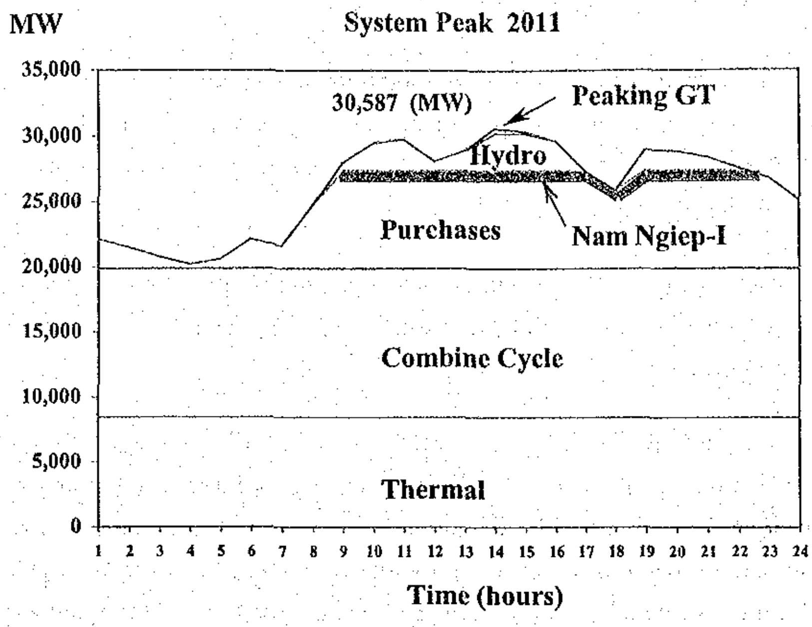


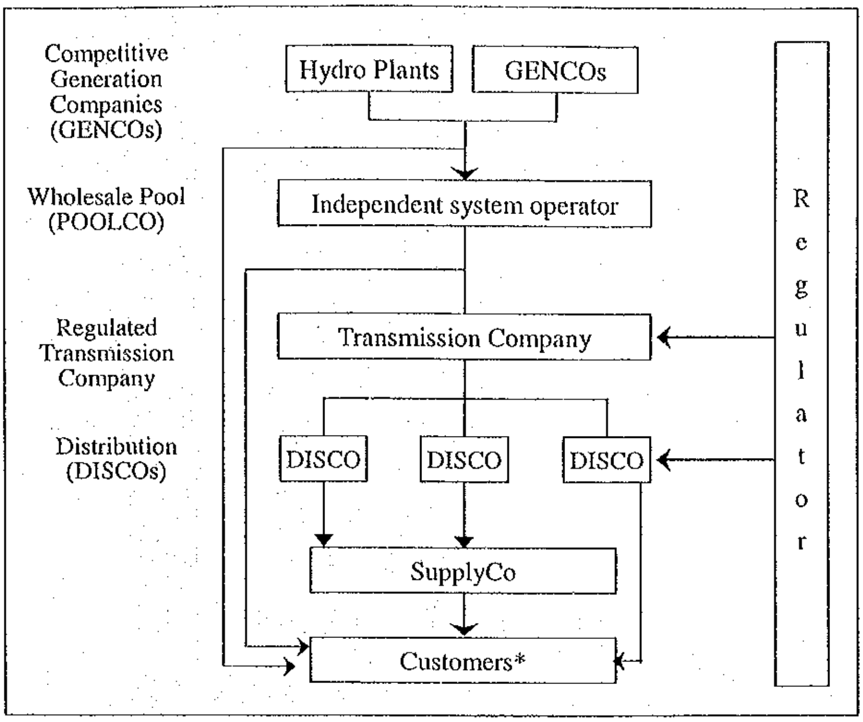
Figure 3.1 Position of the Nam Ngiep-I in the Daily Load Curve

It is difficult to forecast the power price 10 years from now. We can say, however, future tariffs will increase considerably from the current low level of 4 ¢/kWh. NEPO's Thailand Power Pool and Electricity supply Industry Reform Study (Phase I) report states "the pool prices will be low in early part of 2000s reflecting large excess capacity, but pool prices will sharply increase in the period 2009-2011 as reserve margin decrease (see Table 3.1) and previously uneconomic generating plants will achieve commercial levels of dispatch".

Thus we have estimated the intermediate peak power prices in year late 2010 in Thailand will be 6-7 ¢/kWh or more. Here we adopt a conservative value of 6.0 ¢/kWh as an expected export tariff in financial and economic evaluations to be discussed in Chapter 5.

A competitive power pool will be in place by late 2010 when Nam Ngiep-I HEPP is scheduled for commissioning (see Figure 3.2). According to the Thailand Power Pool market rules (draft 2.0 dated April 2001) the wholesale electricity market will consists of a power pool comprising two spot markets (electricity and spinning reserve) and a bilateral contract market which is outside pool settlement (see Figure 3.3).

It is difficult to predict what impact the power pool may have on electricity prices. Much of the hydropower trade with long-term PPAs will not go through the power pool but will be on a direct bilateral contract between generators and bulk purchasers (Discos, Supplycos, etc). Essentially the same pricing mechanism will exist for the exporting IPPs as exist at present, that is the price will be dictated by the least cost alternative available to the purchaser for long term power contracts. It is expected that this will apply to most power export agreements for firm (primary) hydro power.



Note: * Customers with demand over a certain threshold will be able to purchase electricity directly from gencos or power pool. The regulator will be responsible for determining the detail of the qualified customers.

Source: NEPO

Figure 3.2 Long Term Energy Supply Structure

Normally the principle of competition operates in a pool market in which many power companies participate, leading to declines in the market price below that which existed prior to introducing the pool. Even under these conditions, however, it appears to be inconceivable that the market price will differ substantially from the benchmark price discussed above. The current PPA market price with EGAT is set under conditions of fierce competition between IPPs, and applicable cost minimization proposals are reflected at EGAT. It is difficult to believe that the pool market will create further downward pressure on prices, and consequently even under the pool market, the aforementioned benchmark price levels are likely to be maintained.

The conclusion of power market analysis follows. During 2011 when Nam Ngiep-I HEPP is scheduled for commissioning, it will be necessary for Thailand to find between 2,300 MW and 2,800 MW in new power sources. This project is one of the promising candidates for providing this power. The market will easily absorb around 240 MW, but in order to succeed in competition with other market participants the project must be able to operate as an intermediate load plant at the projected benchmark price of 6.0 ¢/kWh (and at a utilization rate of at least 50%). The decisive factors in succeeding as a private sector IPP will be whether revenues attractive to investors in the private sector can be achieved at the benchmark price levels, and whether a financing package can be created at low interest rates so profits can be earned.

Table 3.1 Thailand (EGAT) Load Forecast and Generation Development Plan

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Electricity Demand																	
Maximum Demand; MW	14,918	16,184	17,388	18,587	19,913	21,222	22,552	23,951	25,450	27,232	28,913	30,587	32,405	34,352	36,366	38,519	40,699
Annual Increase	14,918	1,266	1,204	1,199	1,326	1,309	1,330	1,399	1,499	1,782	1,680	1,675	1,818	1,947	2,014	2,153	2,180
Annual Load Factor	74.1	73.0	72.8	72.8	72.5	72.5	72.8	72.8	72.9	72.7	72.7	72.8	72.8	72.8	72.9	72.9	73.0
Energy Sent; GWh	96,781	103,496	110,945	118,540	126,449	134,794	143,748	152,743	162,438	173,532	184,213	194,930	206,660	219,134	232,106	245,943	260,262
Annual Increase	6,367	6,715	7,449	7,595	7,909	8,345	8,954	8,995	9,695	11,094	10,681	10,717	11,730	12,474	12,972	13,842	14,314
GDP Growth Rate	3.67	4.42	4.80	4.90	4.68	4.56	4.62	4.86	4.74	4.73	4.63	4.55					
GDP elasticity of electricity demand	2.40	1.92	1.55	1.41	1.52	1.44	1.36	1.28	1.32	1.43	1.33	1.27					
Installed Generating Capacity (end of year); MW																	
EGAT																	
Hydro Power Plant	2,880	2,886	3,386	3,386	3,386	3,386	3,386	3,386	3,386	3,386	3,326	3,386	3,386	3,386	3,386	3,820	4,046
Plant added (net)	0	0	500	0	0	0	0	0	0	0	0	0	0	0	0	440	220
Thermal Power Plant	7,238	6,255	5,855	6,155	5,845	5,845	5,225	5,225	5,225	5,075	5,075	5,075	5,000	5,000	4,450	3,600	3,300
Plant added (net)	0	-973	-400	300	-310	0	-620	0	0	-150	0	0	-75	0	-550	-850	-300
Combined Cycle Plant	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,632	5,632	6,325	7,207	7,207	7,207	6,852	6,852	6,162	5,855
Plant added (net)	0	0	0	0	0	0	0	557	0	693	882	0	0	-355	0	-690	-307
Gas Turbines	682	785	819	819	453	453	453	453	453	453	453	453	453	453	453	453	453
Plant added (net)	0	123	34	0	-366	0	0	0	0	0	0	0	0	0	0	0	0
Total Generation EGAT	15,845	15,001	15,135	15,435	14,759	14,759	14,139	14,696	14,695	15,239	16,121	16,121	16,046	15,691	15,141	14,041	13,654
Total Plant added (net)	0	-844	134	300	-676	0	-620	557	0	543	882	0	-75	-355	-550	-1,100	-387
Purchased Power																	
EGCO, IPP, RGCO																	
Thermal (Oil, Coal)	150	1,620	1,620	1,620	1,620	2,354	3,754	5,101	5,101	5,101	5,101	5,101	5,101	5,027	5,026	5,026	5,036
Plant added (net)																	
Combined Cycle	3,306	3,306	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544	6,544	5,928	5,620	5,312	5,312	5,312
Plant added (net)																	
New Capacity	0	0	0	0	0	0	0	0	0	0	700	3,000	5,800	8,600	11,800	15,300	18,300
Plant added (net)											700	2,300	2,800	2,800	3,200	3,500	3,000
Total EGCO, IPP, RGCO	3,456	4,926	8,164	8,164	8,164	8,898	10,298	11,645	11,645	11,645	12,345	14,645	16,829	19,247	22,138	25,638	28,618
Plant added (net)	3,456	1,470	3,238	0	0	734	1,400	1,347	0	0	700	2,300	2,184	2,412	2,891	3,500	3,000
SPP	1,433	1,678	1,777	1,967	1,967	1,967	1,967	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057	2,057
Plant added (net)	90	245	99	190	0	0	0	0	0	0	0	0	0	0	0	0	0
Import from Laos																	
Theun-Hinboun	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214
Houay Ho	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
Import 2007	0	0	0	0	0	0	0	1,903	1,903	1,903	1,903	1,903	1,903	1,903	1,903	1,903	1,903
Import 2008	0	0	0	0	0	0	0	0	1,380	1,380	1,380	1,380	1,380	1,380	1,320	1,380	1,380
Total import from Laos added in year	340	340	340	340	340	340	340	2,243	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623
Other (TNB, Malaysia)																	
TNB	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Added in year (net)	0	0	300	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchased	5,229	6,944	10,581	10,771	10,771	11,505	12,905	16,245	17,625	17,625	18,325	20,625	22,809	25,227	28,112	31,618	34,618
Added in year (net)																	
Total Generating Capacity (end of year)	21,074	21,945	25,716	26,206	25,510	26,264	27,044	30,941	32,321	32,864	34,446	36,746	38,855	40,918	43,259	45,659	48,272
Total Capacity added in year (net)	1,974	872	3,771	450	-676	734	780	3,897	1,380	543	1,582	2,300	2,109	2,063	2,341	2,400	2,613
Dependable Generating Capacity at System Peak in Year	20,398	21,117	21,354	25,102	24,436	24,730	26,000	27,994	31,171	30,975	33,296	35,596	37,705	39,767	39,647	44,509	47,122
Reserve Margin (% of Peak Demand); target minimum is 15 %	36.73	30.48	32.23	35.05	22.97	18.28	15.29	16.88	22.48	15.31	15.16	16.38	16.36	15.76	13.61	15.55	15.78

Source : EGAT PDP 2001

Table 3.2 Power Development Program of Thailand (2001-2016)

	Projects	Capacity (MW)	Commissioning Schedule
Committed Projects	Lam Takong Pumped Storage	2x250	Oct 01 – Nov 01
	Ratchaburi Combined Cycle Block #1	725	Nov 01
	Ratchaburi Combined Cycle Block #2	725	Dec 01
	HVDC Link with Malaysia	300	*Dec 01*
	Ratchaburi Combined Cycle Block #3	725	Apr 02
	IPP (Bowin Power)	2x356.5	Apr 02
	Lan Krabu Gas Turbine	122	Jun 02
	IPP (Eastern Power)	350	Jul 02
	Krabi Thermal	300	Dec 03
	IPP (Gulf Power Generation)	2x367	Oct 04 – Apr 05
	IPP (Union Power Development)	2x700	Oct 05 – Jan 06
	IPP (BLCP Power)	2x673.25	Oct 06 – Feb 07
	Total Commited Capacity	**7,940.5 MW**	
	South Bangkok Renovation	2x693	Jan 07 – Apr 09
	North Bangkok Renovation	625	Jan 07
	Power Purchase from Laos	1,903	Sep 07
Future Candidate Projects	Power Purchase from Laos	1,380	Mar 08
	Bang Pakong Renovation	2x441	Oct 09 – Apr 2010
	New Capacity (domestic/foreign)	700	Oct 2009
	New Capacity (domestic/foreign)	2,300	Oct 2010
	New Capacity (domestic/foreign)	2,800	Oct 2011
	New Capacity (domestic/foreign)	2,800	Oct 2013
	New Capacity (domestic/foreign)	3,200	Oct 2014
	New Capacity (domestic/foreign)	3,500	Oct 2014
	Kirithan Pumped Storage	3x220	Oct 2014 – Oct 2015
	New Capacity (domestic/foreign)	3,000	Jan 2016
	Installed Capacity (As of August 2001)	21,939.8 MW	
	Capacity Additions	33,076.5 MW	
	Purchase from SPPs	383.8 MW	
	Capacity Retirements	7,128.6 MW	
	Net Capacity Increase	26,331.7 MW	
	Total Installed Capacity (at the end of 2016)	48,271.5 MW	

Source : EGAT PDP 2002 September 2001

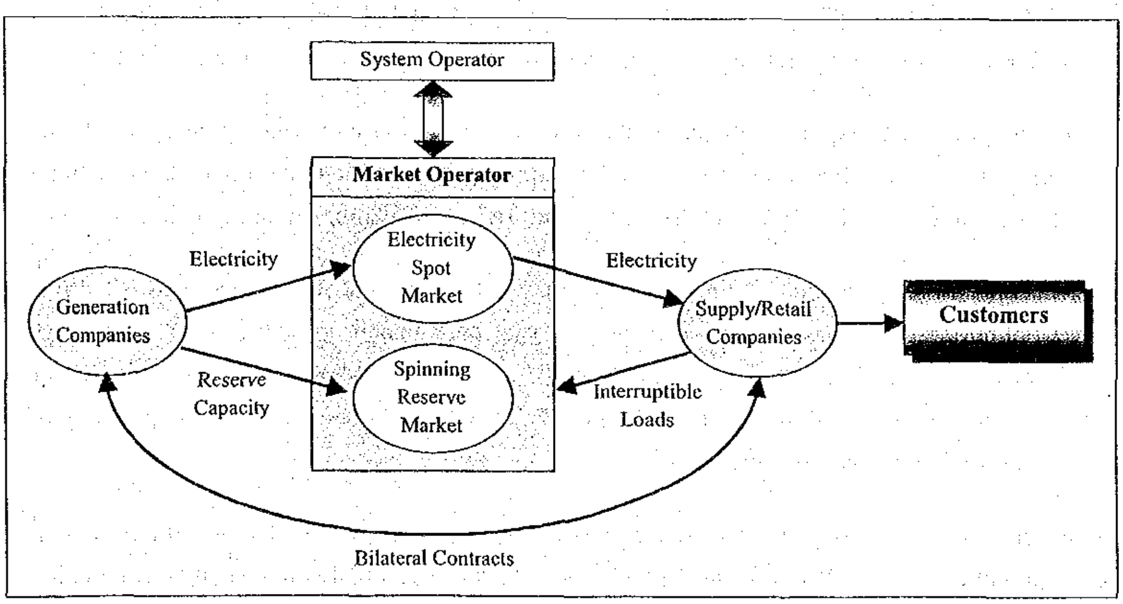


Figure 3.3 Thailand Wholesale Electricity Market

3.5 EXPORT POTENTIAL TO VIETNAM

EVN's recent power development plan (see Table 3.3) indicates power purchase from abroad will be necessary in year 2007. A total of 34,791 MW new capacity will be required by 2020:30,791 MW will be produced within the country and 4,000 MW will be purchased from abroad.

The existing MOU between the GOL and the Vietnam Government provides for the export of 1,000 MW of hydropower from Lao to Vietnam over the next ten years. More specifically EVN intends to import 300 MW in 2007, 400 MW in 2009 and 300 MW in 2010.

The current GOL plan provisionally list the following projects as hydro candidates for power export to Vietnam (See Table 3.3).

Nam Mo	105 MW	(COD 2007)
Xe Kaman 3	218 MW	(COD 2012)
Nam Kong 1	240 MW	(COD 2012)
Sekong 4	440 MW	(COD 2014)
Sekong 5	253 MW	(COD 2014)
Nam Theun 1	400 MW	(COD 2014)
Nam Theun 3	236 MW	(COD 2016)
Total	1,892 MW	

Price considerations are as follows:

(i) Average production cost in Vietnam is fairly low, around 3 US Cent/kWh. Current price of natural gas in Vietnam is also lower than that in Thailand. The PSSS report also indicates that tariff limit for electricity import is around to 4.2 US Cent/kWh currently set for power purchase from its domestic IPPs.

(ii) According to EDL's explanation to the study team (July 2001), GOL's recent negotiation with Vietnam on energy export has no major technical issues but made no remarkable progress. Vietnam asks GOL to set fixed border energy price at US Cent 4.0 US ¢/kWh, because of fairly lower energy production cost in Vietnam. The negotiation is to continue further.

As such the pricing for export to Vietnam is severe in comparison with Thai counterpart. However, considering the rather demanding generation development plan of Vietnam, difficulties in financing and delays in national projects may yet give higher priority to the planned imports from Lao PDR.

Vietnam does not have an extensive history of IPP projects. The first such project was the IPP (Hiep Thuoc) falling under the first category for an industrial park which opened in 1998. The next IPP project was Nomura Corporation's captive power generator (50MW diesel) for the Hai Phong Industrial plant. Bien Hua (Banou, Amata Power) of 120 MW gas-fired plant is also operating. So far three IPP projects are under operation.

Discussions for several IPPs to operate on a BOT basis started in 1997. It should be noted that successful conclusion of PPAs for Phu My 2.2 and 3 have proved that complex BOT IPP deals were possible in Vietnam. A power tariff set in PPAs of both projects is around 4.0 US ¢/kWh.

Table 3.3 Power Generation Plan 2000-2020 (Base Case)

No.	Year / Type Plant	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
	CAPACITY (MW)													
1	Hydro power	3,234	3,830	4,066	4,138	4,138	4,508	4,901	5,371	5,871	6,141	6,461	10,206	12,794
2	Pump storage power												400	1,000
3	Imported power								300	300	600	1,000	2,000	4,000
4	Coal TP	640	1,240	1,340	1,440	1,890	1,890	1,890	2,190	2,490	2,640	2,940	3,340	4,840
5	Gas + Oil TP	2,252	2,701	2,521	2,953	3,823	4,777	5,137	5,497	5,857	6,217	6,517	8,737	10,857
6	Geo-thermal						50	100	100	100	100	100	100	100
7	Nuclear energy													1,200
	Total capacity	6,126	7,771	7,927	8,531	9,851	11,225	12,028	13,458	14,618	15,698	17,018	24,783	34,791
	Peal Load	4,487	5,012	5,598	6,253	6,985	7,802	8,454	9,160	9,925	10,755	11,653	17,847	26,854
	Reserve Margin													
	- Rain season	36.5%	55.0%	41.6%	36.4%	41.0%	43.9%	42.3%	46.9%	47.3%	46.0%	46.0%	38.9%	29.6%
	- Dry season	8.7%	34.9%	24.5%	20.0%	18.4%	22.7%	26.0%	30.4%	31.1%	32.1%	32.7%	30.0%	23.1%
	POWER GENERATION CAPACITY RATIO (%)													
1	Hydro power	52.8%	49.2%	51.3%	48.5%	42.0%	40.2%	40.8%	39.9%	40.1%	39.1%	38.0%	41.2%	36.8%
2	Pump storage power												1.6%	2.9%
3	Imported power								2.2%	2.1%	3.8%	5.9%	8.1%	11.5%
4	Coal TP	10.4%	16.0%	16.9%	16.9%	19.2%	16.8%	15.7%	16.3%	17.0%	16.8%	17.3%	13.4%	13.9%
5	Gas + Oil TP	36.8%	34.8%	31.8%	34.6%	38.8%	42.6%	42.7%	40.8%	40.1%	39.7%	38.2%	35.3%	31.2%
6	Geo-thermal						0.4%	0.8%	0.8%	0.7%	0.6%	0.6%	0.4%	0.3%
7	Nuclear energy													3.4%
	TOTAL	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Source: EVN, Electricity Market in Vietnam for Period 2001-2020, October 2000

4. HYDROPOWER PLAN

4.1. SITE CONDITIONS

(1) Location and Topography

The Nam Ngiep River is a left bank tributary of the Mekong River, with the confluence about 7 km upstream of the town of Pakxan (Paksane). The source of the Nam Ngiep is near the town of Xieng Khouang (Phonsavan). The Nam Ngiep River flows from north to south though a dense forest area between its origin on the Tra Ninh plateau at EL.1,200 m and the Mekong plain at EL.160 m. Its total length is 160 km, and it drops a total of 1,300 m along its course. At its confluence with the Mekong, the Nam Ngiep has a total catchment area of 4,510 km^2. The proposed Nam Ngiep-I dam site is located at 18°39'N and 103°30'E. The catchment area at the proposed dam site is 3,700 km^2.

(2) Geology

MAIN DAM SITE

Stratigraphy of geological layers was found to be composed of six layers. A folding structure runs along the Nam Ngiep river from upstream around the confluence with Nam Katha river to downstream on the right bank. It is estimated that the dislocation by this folding is about 70 m and the formation on the right bank is higher than that on the left bank. The loose deposits covering the surface were found about 5 m thick on the left bank and about 5 to 20 m thick on the right bank. Due to the folding structure, talus deposits are the most thick at the foot of the slope near the Nam Ngiep riverside. The fresh hard rock are found about 30 m below ground surface. At the folding area, it is around 50 m deep from the ground surface.

Foundation rocks of CH class are strong enough for the dam, with unconfined strength for conglomerate 1000 - 2000 kgf/cm^2, sandstone 600 - 1500 kgf/cm^2 and mudstone 250 - 770 kgf/cm^2. The strength of mudstone varies and weaker and swelling with moisture is suspected for a part of mudstone. The fresh rock is enough watertight and low in permeability for the dam foundation. The weathered zone is some more permeable, however, it can be treated by curtain grouting to make a impermeable wall. In the folding structure weathered zone is found thick, and erodibility of unconsolidated materials there are taken into account for CFRD foundation design.

RE-REGULATING WEIR SITE

On parts of both banks there are outcrops of mudstone, so alluvial river deposits are not expected to be so deep. According to core drilling result, foundation rock of mudstone is available on the left bank at the depth of 6.7m and on the right bank at the depth of 1.5m.

CONSTRUCTION MATERIALS

Granite, which is considered available as concrete aggregates, is distributed in B.Sopyouk quarry site which is located upstream of the dam site. However, according to core drilling results there, it is covered with thick weathering zone about 30 m and fresh rock could not be reached within 50 m drilling depth. It is necessary to find locations where the covering depth is less around this place.

Hard conglomerate and sandstone are distributed abundantly around the dam site. These may used for rockfill materials, but sandstone and conglomerate from Mesozoic(Cretaceous to Jurassic) formations are susceptible of cement-aggregate combinations to expansive reactions.

(3) Hydrology

LOW FLOW ANALYSIS

The runoff records at Ban Hatkham water level gauging station near the proposed dam site in Nam Ngiep River are only available for 3 years between 1998 to 2001. Therefore, the observed daily discharge at the Muang Mai gauging station (available 20 years) are used to estimate long-term discharge at the proposed Nam Ngiep-I dam site. Along this line, the Tank model (*Sugawara*, 1956) method is applied in this study as a rainfall-runoff model, the parameters of which are calibrated by using rainfall and available runoff records.

Using the Tank model, the daily stream flow sequences at the proposed Nam Ngiep-I Dam site for the period 1971-2000 (30 years) are estimated. The mean annual discharge at the proposed dam site (catchment area of 3,700 km^2) is 147.2 m^3/sec (1,259 mm/annum), with the runoff coefficient of 0.67 (= MAR/MAP = 1,259/1,873 = 0.67) as shown below:

C.A.[km2] 3,700

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
Basin Mean Rainfall	mm	8.0	16.8	37.6	104.4	231.2	360.6	402.3	379.7	230.0	85.9	12.9	3.9	1,873.4
Avearge Runoff	m^3/sec	76.1	64.8	56.9	65.5	112.3	215.4	272.3	291.6	254.7	157.0	110.0	90.4	147.2
Avearge Runoff	mm	55.1	42.4	41.2	45.9	81.3	150.9	197.1	211.1	178.4	113.6	77.0	65.4	1,259.4
Runooff Coefficient (Annual Avearge)														0.67

This estimated mean annual runoff (MAR) of 147.2 m^3/sec (= specific yield of 4.38 m^3/sec/100 km^2) for the Nam Ngiep-I dam site is less than previous study results. However, the specific yields of MAR for various hydropower projects in Lao PDR are between 1.34 to 7.59 m^3/sec/100 km^2 (average is 4.28 m^3/sec/100 km^2). Hence, the MAR specific yield of 4.38 m^3/sec/100 km^2 for the Nam Ngiep-I dam site is almost the same as the average of the central (Nam Theum, etc.) or north-west zone near the project site (Nam Ngum, etc.) and well within reasonable range of MAR in this region.

FLOOD ANALYSIS

The unit hydrograph at the Nam Ngiep-I dam site was developed by means of the *Soil Conservation Service* (SCS) synthetic unit hydrograph method. The peak discharge of the 24-hr PMF by *U.S. Weather Bureau* method was estimated as 14,220 m^3/sec. This value is slightly lower than the results of previous study, i.e. 15,900 m^3/sec.

Probable flood discharges for various return periods are estimated based on the observed daily discharge records at the Muang Mai water level gauging station for the period of 1978 to 2000. The estimated probable flood peak discharges at the proposed Nam Ngiep-I dam site for a series of return periods are enumerated in the Table below.

Return Period (Year)	Excess Probability	Flood Peak Discharge (m^3/sec)
1.01	0.9901	680
1.50	0.6667	1,000
2	0.5000	1,150
5	0.2000	1,590
10	0.1000	1,930
20	0.0500	2,300
30	0.0333	2,530
40	0.0250	2,700
50	0.0200	2,840
80	0.0125	3,140
100	0.0100	3,290
200	0.0050	3,800
300	0.0033	4,130
500	0.0020	4,560
1,000	0.0010	5,210
2,000	0.0005	5,930
5,000	0.0002	7,000
10,000	0.0001	7,920

Note: (Peak Discharge at Muang Mai) = (Daily Mean Maximum Discharge at Muang Mai) x 1.2
(Dam Site Flow) = (Muang Mai Flow) x 3,700 / 4,320
Frequency curve was applied "Log Peason Type-III"

4.2. OPTIMUM PLAN FORMULATION

(1) Reservoir Operation

In order to select the optimal development scale of the Nam Ngiep-I HEPP, a reservoir operation analysis was undertaken by establishing a simulation model, then power output and annual energy production were calculated for the selected alternative scales. The operation as an intermediate power plant was considered in this study for the Nam Ngiep-1 power plant. Reservoir operation analysis was conducted for the case of 16-hour operation. It was also assumed that EGAT would not purchase energy from the Project on Sundays and Thai national holidays, thus the power plant for export would cease for 60 days per year.

FSL	312m	316m	320m	324m	328m
16-hour Peak Operation					
MOL (EL.m)	284	288	296	292	296
Maximum Plant Discharge (m3/s)	230	230	230	238	242
Maximum Power Output (MW)	234	242	252	263	276
95% Dependable Peak Power Output (MW)	175	194	190	206	217
Annual Average Peak Energy (GWh)	1,082	1,126	1,173	1,227	1,284
95% Dependable Peak Energy (GWh)	874	932	948	990	1,044
Annual Average Off-Peak Energy (GWh)	152	151	154	142	132
Annual Average Total Energy (GWh)	1,234	1,277	1,327	1,369	1,416

Remarks; The above values were as estimated for the optimum MOL for respective FSLs. Maximum power output mentioned above is against average combined efficiency.

(2) Reservoir Inundation

Elevations of villages in the Thaviang Sub-District were checked on the 1:10,000 scale maps. Except B. Pou of which relocation in near future is scheduled by a national plan irrespective to the Project, the lowest village in elevation was B. Phiangta at EL.321 m. Calculation result of the land use classifications below respective elevations in the Thaviang Sub-District shows that each classified area noticeably increases in case the elevation surpasses EL.320 m in general.

No.	Village	EL. (m)
1.	B. Pou	316
2.	B. Naphang	324
3.	B. Hatsamkone	326
4.	B. Phiangta	321
5.	B. Dong	326-330
6.	B. Phonyeng	326-330
7.	B. Naxong	330
8.	B. Naxay	338
9.	B. Viengthong	343

The backwater effect at the upstream reach of the reservoir was evaluated for the FSL.320 m case, and the following are found:

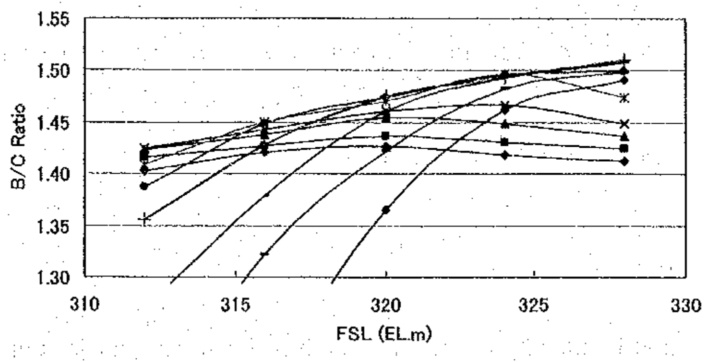
(i) Water surface profiles at B.Dong and its upstream reach do not change substantially before or after dam construction, even considering sediment in the reservoir. Therefore, a backwater effect would not occur there due to reservoir water level.

(ii) For B.Phiangta in the case of flood discharge at the dam site less than 2,000 m^3/s, there would occur a backwater effect but still not higher than EL.321 m. If the discharge is more than 2,000 m^3/s, the water level before and after dam construction becomes similar, so there would exist no backwater effect.

(iii) In case that sedimentation accumulates in the reservoir, there is a possibility that some backwater effect would occur in B.Phiangta. Dredging the sedimentation and lowering the full supply level of the reservoir are considered as the countermeasures, and the former option is suggested as more economical.

(3) Optimum Formulation for Power Export

The criteria used in this study to decide the optimum development scale were; i) to achieve the highest benefit/cost (B/C) ratio, and ii) to avoid inundation of villages and paddy fields of the Thaviang Sub-District, except B. Pou of which relocation in near future is scheduled by an unrelated national plan.



As foreseen in the Phase I Study, the higher FSL brings the higher B/C. Meanwhile, in order to avoid inundation of villages (except B.Pou) in the Thaviang Sub-District, it is suggested the FSL be set below or equal to EL.320 m. The highest B/C under FSL.320 m is attained in case of MOL.296 m. The operational characteristics resulting from the study for the optimum scheme are as follows:

No.	Item	Optimum Scale
1.	FSL	EL.320m
2.	MOL	EL.296m
3.	Max. Plant Discharge	230 m^3/s
4.	Installed Capacity	260 MW
5.	Average Annual Peak Energy	1,173 GWh/year
6.	Average Annual Total Energy	1,327 GWh/year

(4) Optimum Formulation for Domestic Power Use

According to the power policy in Laos, IPP plants for power export are expected to allocate some of their capacity (at least 5% of the output) for domestic use. As there already exists 22 kV transmission line in the vicinity along National Road 4 from Pakxan to Bolikham, the allocated power from the Project would be utilized by connecting to EDL's grid system, not for an isolated off-grid.

It is possible that if the Nabong collector substation is completed and ready for step down from 230 kV to 115 kV, such domestic off-take arrangement might be conducted at the said substation. However, as there exists some uncertainty in implementation schedule of this collector substation, providing an additional independent power unit is considered as a safe option. Allocating power from the export units to the EDL's grid system, not by way of the Nabong substation, is technically difficult due to stability reason of the both EGAT's and EDL's grid systems.

The B/C ratio analysis aforementioned indicates that domestic off-take arrangements for this Project can be achieved most economically if the independent power unit is provided at the re-regulating weir. The operational characteristic for the scheme are as follows:

No.	Item	Optimum Scale
1.	FSL	EL.181m
2.	MOL	EL.176m
3.	Max. Plant Discharge	160 m^3/s
4.	Installed Capacity	16.8 MW
6.	Average Annual Total Energy	108 GWh/year

4.3. PRELIMINARY DESIGN

(1) Main Dam

The dam layout is composed mainly of two lanes of river diversion tunnels, a main concrete face rockfill dam (CFRD), a spillway with gated overflow portion, an intake structure and power waterway, a surface type powerhouse, outlet facilities, and so on. As the most appropriate dam type, the CFRD is selected taking account the site topography and geology, availability of construction material, and technical as well as cost advantages of this type, compared with the earth core rockfill dam (ECRD) or roller compacted concrete dam (RCC).

In order to avoid excessive excavation at the spillway, the dam axis is selected about 1.1 km downstream from the confluence with the Nam Katha River. The spillway is laid out on the left abutment, while a power intake, an intake gate shaft, a headrace tunnel, a surge tank, penstock, a surface type powerhouse, and an open switchyard are laid out on the right abutment. Two lanes of river diversion tunnels, with a bottom outlet, are also laid out on the right abutment.

The dam is 151 m high and the total embankment volume is around 7.3 million m^3 with the upstream and downstream slopes of 1:1.4. Rock materials to be used for the dam embankment are conglomerate and sandstone which would be excavated from the spillway site and quarries.

(2) River Diversion

During the construction, the river water will be diverted via two diversion tunnels driven through the right abutment. Separate main cofferdams will be provided at the upstream and downstream sides of the main dam. After completion of river diversion function, one of the tunnels (Diversion Tunnel No.1) will be permanently plugged, while an outlet will be installed in the other tunnel (No.2). So as to prevent clogging at the inlet due to silting, vertical shaft and trash beam structure will be provided at the No.2 tunnel.

Referring to the practice in precedent studies in Laos, the 25-year recurrence flood of 2,420 m^3/s is adopted for CFRD in this Project. The diversion tunnels are 9.2 m in diameter, and their length are 1,176 m and 1,079 m, respectively. A 46.5 m high cofferdam is laid at the upstream side of the main dam.

(3) Spillway

The spillway is a gated overflow structure located on the left abutment of the main dam. The overflow section is designed to have four (4) 12.25 m wide and 16.5 m high radial gates. Dimensions of this section are determined so that the discharge per unit width might not surpass 200 $m^3/sec/m$, and also that the gate height might not surpass 20 m. This overflow weir discharges the peak of the 1,000-year recurrence probable flood of 5,210 m^3/s at FSL 320 m at full gate opening. At PMF, maximum outflow from the spillway during the routing of PMF becomes 7,860 m3/s and reservoir level corresponding to this discharge is FWL.324.2 m.

The spillway chute conveys the discharge released from the reservoir smoothly. The chute width is decided to be 58 m. The training wall height is set at 7.6 m so as to discharge PMF outflow of 7,860 m^3/s without overtopping. The stilling basin is a standard apron type designed against the 100-year recurrence probable flood outflow of 3,290 m^3/s. The length of the stilling basin is set at 114 m, and the bottom level at EL.168 m.

(4) Bottom Outlet

Bottom outlet facilities are provided for retardation of reservoir-rise during impoundment, releasing riparian flow to the downstream reach, emergency draw-down, and so on.

An outlet is provided in the diversion tunnel No.2, which will close after the completion of the main dam. A Howel-bunger valve of 2.5 m diameter has discharge capacity of 200 m^3/s against FSL. A valve chamber is provided in the main plug portion of the tunnel, which will be constructed at the middle of the tunnel stretch. Access to this valve chamber will be made through a gallery arranged at the right bank of with an entrance located at the powerhouse yard.

(5) Intake Structure and Power Waterway

Power intakes, intake gate shafts, headrace tunnels, surge tanks and penstocks are laid on the right abutment of the main dam. The layout of these structures allows for the possibility of future extension of installed capacity from the initial 260 MW (16-hour peak) to 520 MW (8-hour peak). The intake structure and power waterway for the initial 260 MW will be laid on the mountain side, so that future extension will be laid on the river side. The optimization study led to a conclusion of the headrace tunnel diameter of 9 m and penstock diameter of 5.6 m in average. The restricted orifice type surge tank of which chamber diameter is 12 m is also provided.

(6) Power Station for Main Dam

The powerhouse will be located at the down stream of the main dam toe and constructed on ground surface at EL.195 m. This is higher by more than 2 m than the flood level for the 100-year recurrence probable flood with peak discharge of 3,290 m^3/s.

The powerhouse will accomodate two units of the vertical shaft Francis turbines at a setting level of EL 177.5 m which will ensure sufficient suction head for restricting turbine runner cavitation under single unit operation conditions.

The powerhouse design is based on the accommodation requirements of the hydraulic turbines, generators, auxiliary equipment such as cooling water supply pump, governor oil system, turbine control panels, generator exciter and switchgear for main generator circuit and station service power supply. A 245 kV GIS room will be arranged upstream side of powerhouse.

The power station will be provided with two 130 MW units of water turbine generator. The water turbines will be 133.8 MW vertical shaft Francis turbines operated directly coupled with 144 MVA three-phase synchronous of semi-umbrella type.

(7) Re-regulating Weir

The re-regulating weir will be located about 5 km downstream of the proposed dam site. The facility is mainly composed of a concrete face rockfill dam (CFRD), a spillway with gated overflow portion and a surface type powerhouse.

The river diversion for the weir construction is designed as to the 5-year recurrence probable flood of 1,590 m^3/s. The overflow section is designed to have five (5) 12 m wide and 9.5 m high gates. This overflow weir discharges the peak of the 100-year recurrence probable flood of 3,290 m^3/s at FSL 181 m at full gate opening. End of the spillway will be connected to the abutment with CFRD non-overflow weir section. Crest level of the non-overflow sections is set at EL.184 m, which is about 3 m above the full supply level. Impervious fill type non-overflow dykes are to be constructed across the four (4) branch valleys on the river banks.

(8) Power Station for Re-regulating Weir

The powerhouse will have two units of the bulb turbines at a setting level of EL 161 m after considering the effects of turbine runner cavitation under single unit operation conditions.

The powerhouse is designed based on the size of the hydraulic turbines, generators, auxiliary equipment such as cooling water supply pump, governor oil system, turbine control panels, generator exciter and switchgear for generator circuit and station service power supply. 115kV outdoor switchgear will be arranged to connect transmission line for domestic power supply.

The power station will be provided with two 8.4 MW units of water turbine generator. The water turbines will be 8.7 MW bulb type turbines operated directly coupled with 9.3 MVA three-phase synchronous type.

(9) Main Transmission Line and Substation

The transmission line route for the Nam Ngiep-I power station is planned to connect with the Nabon collector substation which will be located 45 km far from the Vientiane and 125.2 km far from the Nam Ngiep-I power station. The transmission line for the Nam Ngiep-I power station will be double circuit with ACSR conductor of 1,297,000 MCM and galvanized steel ground wire of 3/8".

By the time the Nam Ngiep-I project is completed, the main structure of the collector substation would have been in operation for some time, connected to the Thai power system. The Nam Ngiep-I project will therefore bear the cost of the extension bay for 230 kV transmission line, including switchgear equipment with associated control and line protective equipment and civil work. The project will also construct the local power supply lines for supplying power for the project facilities and interconnection of the regulating power station.

(10) Main Transmission Line and Substation

The generated power at the regulating weir power station will be exclusively used for domestic power supply. At present, Pakxan substation is the nearest substation and is 40 km distant. The transmission line to connect the power station and Paxsan substaion will be 115 kV single circuit with ACSR conductor of 150 mm^2 and galvanized steel ground wire of 3/8". The project will bear cost of the extension bay for 115 kV transmission line at Pakxan, including the switchgear equipment with associated control and line protective equipment and civil work. The project will also construct the 22kV local power supply line in the vicinity.

4.4. CONSTRUCTION PLAN AND COST ESTIMATE

(1) Construction Plan

The temporary facilities for the construction works mainly consist of 1) Stockpile and concrete batching plant/ aggregate crushing plant, 2) Contractor's camp, 3) Engineer's site office, and 4) Spoil bank. As shown in the attached drawing, each of the temporary facilities can be located on the flat lands dotted between the dam site and re-regulation weir site downstream of the dam site.

This construction schedule is prepared, provided the EPC contract can be made in the end of June 2005. The following activities are on the critical path in the overall construction schedule.

No.	Work/Event	Schedule
1.	Site investigation and tender design	2003
2.	EPC contract	End of Jun., 2005
3.	Permanent/temporary access road construction	End of Jun., 2005
4.	*Diversion tunnel construction*	*End of Jan., 2006*
5.	River diversion	End of Sep., 2007
6.	Main dam construction	End of Sep., 2008
7.	Reservoir impounding	End of Apr., 2010
8.	Wet test of generating equipment	End of Jun., 2010
9.	Commissioning of generating unit 1	End of Sep., 2010
10.	Commissioning of generating unit 2	End of Oct., 2010

(2) Cost Estimate

The base cost comprises i) Construction cost, ii) Environmental cost, iii) Operation cost for SPC, and iv) Price contingency. The basic conditions and assumption of the cost estimate are as follow:

(i) The price level of the cost estimate is July 2002 when site investigation works was carried out.

(ii) Since almost all the cost components such as labor, materials, and equipment will be obtained from abroad, the project cost is express in US dollar (US$) only.

(iii) The construction cost is estimated with the unit price estimate method in principle. Each of the work quantities is computed from the preliminary design.

(iv) Each of the unit prices of major civil works is developed by a breakdown of unit price. The costs of metal works, generating equipment, transmission line, and substation are estimated from the data obtained from manufacturers and from the recent bidding unit prices of similar projects in Asian countries.

(v) Price contingency is estimated with the assumed price escalation rate of 1.3 % per annum (referring to current USA consumer price index movements).

(vi) All kinds of tax are excluded from the cost estimate.

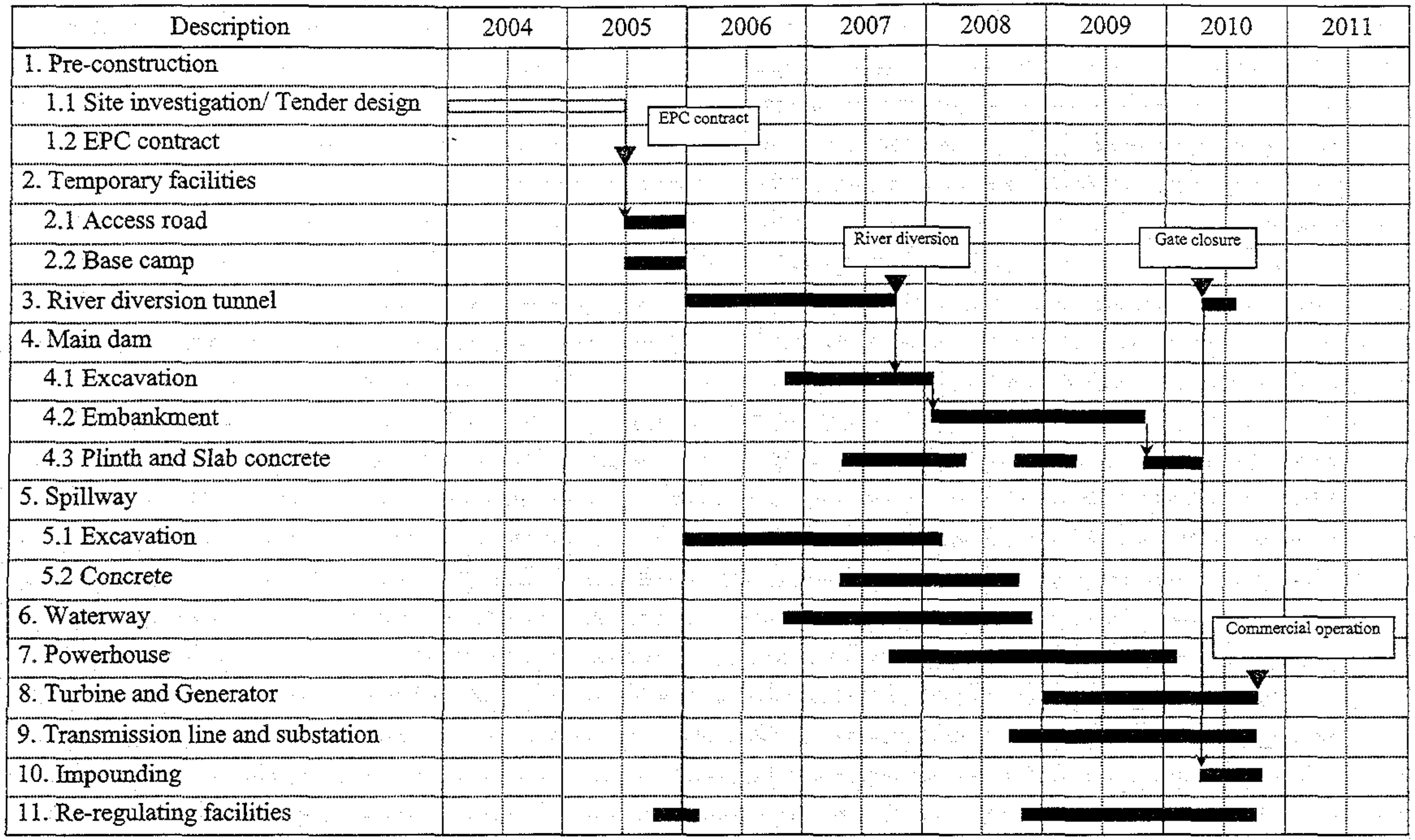
Total base cost is estimated at about US$ 343.7 x 10^6 as summarized below.

No.	Particular	Cost (US$)
1.	Construction Cost	**291,781,840**
1.1	Civil Works	178,411,440
1.2	Metal Works	20,287,000
1.3	Generating Equipment	59,137,400
1.4	Transmission Line and Substation	33,946,000
2.	Environmental Cost	**16,473,260**
2.1	Environmental Monitoring and Planning	9,669,000
2.2	Resettlement Cost	6,804,260
3.	Operation Cost for SPC	**10,290,100**
3.1	Site Investigations and Tender Design	4,125,000
3.2	Administration for SPC	6,165,100
Sub-total	(1 to 3)	**318,545,200**
4.	Price Contingency	**25,167,410**
Total	**Base Cost (1 to 4)**	**343,712,610**

The annual disbursement schedule is made in accordance with the base cost and the construction schedule as summarized below.

Year	Amount (1,000US$)
2005	26,481.9
2006	23,007.0
2007	83,929.6
2008	86,533.4
2009	72,418.4
2010	51,342.3
Total	343,712.6

Construction Schedule



Salient Features of Promising Scheme

Place	Particular	Unit	FSL.320m
Reservoir	Catchment area at dam site	km^2	3,700
	Annual basin rainfall	mm	1,873
	Annual mean runoff	m^3/s	147.2
	Annual mean runoff	mill. m^3	4,642
	Average run-off coefficient	-	0.67
	Probable max. flood, PMF	m^3/s	14,220
	Mean annual sediment flow	$t/km^2/yr$	500
	Reservoir area at FSL	km^2	66.94
	Gross reservoir capacity	10^6m^3	2,241.2
	Min. operation level (MOL)	EL.m	296
	Draw-down	m	24
	Effective storage volume	10^6m^3	1,191.8
Main Dam	Dam type	-	CFRD
	Dam crest level	EL.m	325
	Parapet wall top level	EL.m	325.7
	Plinth bottom level	EL.m	174
	Dam height	m	151
	Dam crest width	m	10
	Dam crest length (in total)	m	513
	Upstream embankment slope	-	1:1.4
	Downstream embankment slope	-	1:1.4
	Face slab thickness	m	0.3 to 0.8
	Plinth apron width	m	4 to 12
	Curtain grout row numbers	nos	1 or 2
	Curtain grout depth	m	25 to 100
	Consolidation grout row numbers	nos	2
	Grouting tunnel length	m	30 and 100
	Dam embankment volume	10^6m^3	7.3
River Diversion	Design flood capacity for diversion	m^3/s	2,420 (Q=25yr)
	Tunnel lane numbers	nos	2
	Tunnel diameter	m	9.2
	Tunnel length	m	1,176 and 1,079
	Tunnel inlet level	EL.m	191.5
	Tunnel outlet level	EL.m	180.5
	Inlet tower top level (tunnel No.2)	EL.m	231
	Upstream cofferdam crest level	EL.m	228.5
	Upstream cofferdam height	m	46.5
Spillway	Design flood capacity for FWL	m^3/s	14,220 (Q=PMF)
	Design flood capacity for FSL	m^3/s	5,210 (Q=1,000yr)
	Design flood capacity for stilling basin	m^3/s	3,290 (Q=100yr)
	Spillway pier top level	EL.m	325
	Forebay sill level	EL.m	300
	Overflow crest level	EL.m	305
	Spillway gate numbers	nos	4
	Spillway gate width	m	12.25
	Spillway gate height	m	16.5
	Overflow weir length	m	33
	Chute width	m	58
	Chute length (horizontal)	m	250
	Slope of chute	-	1:1.99
	Stilling basin bottom level	EL.m	168
	Stilling basin width	m	58
	Stilling basin length	m	114

Place	Particular	Unit	FSL.320m
	Spillway excavation volume	10^6m^3	5.8
	Spillway concrete volume	10^3m^3	135
Bottom Outlet	Discharge capacity of outlet valve	m^3/s	200 (FSL.320m)
	Diameter of outlet valve	m	2.5
	Access gallery length	m	410
	Plug length in diversion tunnel	m	45
Power Intake	Design discharge	m^3/s	230
	Inlet forebay sill level	EL.m	262
	Inlet sill level	EL.m	263
	Inlet width	m	6.0 x 2
	Inlet height	m	5.25 x 4
	Intake shaft height	m	53
Headrace Tunnel	Lane numbers	nos	1
	Tunnel diameter	m	9
	Tunnel length	m	504
	Tunnel slope gradient	-	1:500
Surge Tank	Surge tank type	-	Restricted orifice
	Main tank shaft diameter	m	12
	Main tank shaft top level	EL.m	333
	Main tank shaft bottom level	EL.m	288
	Main tank shaft height	m	45
Penstock	Lane numbers	nos	1 (tunnel) to 2 (open)
	Penstock tunnel length	m	50
	Open penstock length (horizontal)	m	243
	Penstock diameter	m	8.0 to 4.0
	Steel penstock weight	ton	2,100
Power Station (Main Dam)	Design flood discharge for yard	m^3/s	3,290 (Q=100yr)
	Powerhouse yard level	EL.m	195
	Powerhouse type	-	Surface type
	Powerhouse length	m	70
	Powerhouse width	m	50
	Powerhouse height	m	46
	Turbine center level	EL.m	177.5
	Tail water level	EL.m	181.4
	Rated head	m	127.7
	Type of turbine	-	Vertical Francis
	Number of unit	No.	2
	Plant capacity	MW	260
	Peak operation hour	hour	16
	Annual energy	GWh	1,327
	Switchgear type	-	GIS
Re-regulating Pond	Full Supply Level (FSL)	EL.m	181
	Pond area for FSL	km^2	1.1
	Gross storage capacity	10^6m^3	8.2
	Min. operation level (MOL)	EL.m	176
	Effective storage volume	10^6m^3	4.7
Re-regulating Weir	Weir type	-	CFRD with spillway
	Weir crest level	EL.m	184
	Design flood capacity for FSL	m^3/s	3,290 (Q=100yr)
	Check gate numbers	nos	5
	Check gate width	m	12
	Check gate height	m	9.5
	Overflow crest elevation	EL.m	172
	Stilling basin bottom level	EL.m	163
	Design flood capacity for diversion	m^3/s	1,590 (Q=5yr)
	Diversion channel width	m	50

Place	Particular	Unit	FSL.320m
Power Station (Re-regulating Weir)	Design flood discharge for yard	m^3/s	3,290 (Q=100yr)
	Powerhouse yard level	EL.m	184
	Powerhouse type	-	Surface type
	Powerhouse length	m	49
	Powerhouse width	m	26
	Powerhouse height	m	30
	Turbine center level	EL.m	161
	Tail water level	EL.m	167.3
	Rated head	m	12.0
	Design discharge	m^3/s	160
	Type of turbine	-	Tubular
	Number of unit	No.	2
	Plant capacity	MW	16.8
	Peak operation hour	hour	24
	Annual energy	GWh	108
	Switchgear type	-	Outdoor switchyard
Transmission Line	Capacity for main P/S	kV	230
	Distance from main P/S to Nabong	km	125.2
	Capacity for re-reg. P/S	kV	115
	Distance from re-reg. P/S to Pakxan	km	40
Permanent Access Road	B.Nonsomboun to B.Hatkham	km	20.9
	B.Hatkam to dam site	km	12.1

5. FINANCIAL AND ECONOMIC EVALUATION

5.1 GENERAL

Project evaluation to see viability of the Project is conducted from two view-points. Financial evaluation is made from the view-point of the project company while economic evaluation, from the perspective of the Lao PDR economy all a whole. The two evaluation methods are compared in the following table:

Evaluation Method	Viewed from	Benefit & Cost	Evaluation Indicator	Criteria (Target)
Financial Evaluation	Project company	Benefit: Power sales revenue Cost: Capital cost, O&M cost, Taxes	FIRR	12% and more than weighted average cost of capital (WACC)*
Economic Evaluation	National economy	Benefit: Dividend, Royalties and Taxes Cost: GoL's capital contribution and equity investment	EIRR	More than 12% (ADB criteria)

Note: WACC=Expected ROE x Equity Share (%) + Loan Interest Rate x Loan Share (%)

5.2 BASIC ASSUMPTIONS

The following general assumptions were adopted for base case scenario:

- Plant Capacity: 260 MW (export) and 16.8 MW (domestic supply)
- Energy Generation and Sales:

Items	Export (Primary Energy)	Export (Secondary Energy)	Domestic Supply	Total
Generation	1,173 GWh	154 GWh	108 GWh	1,435 GWh
Transmission loss	3.0%	3.0%	3.0%	3.0%
Sales	1,138 GWh	149 GWh	105 GWh	1,392 GWh

- Tariff
  - Export (Primary energy) 6.0 US cent/kWh at COD, escalating at 1.3% p.a.
  - Export (Secondary energy) 3.0 US cent/kWh at COD, escalating at 1.3% p.a.
  - Domestic supply 5.2 US cent/kWh at COD, escalating at 1.3% p.a.

  (Note: COD is scheduled to be October 2010)

- Loan to Equity ratio : 70/30
- Equity Share of GoL : 30%
- Loan financing : Multilateral agency (40%) 6% interest, repayable in 15 years
  Export credit agency (30%) 8% interest, repayable in 12 years
  Commercial banks (30%) 12% interest, repayable in 8 years
- Concession period: 25 years from COD
- Royalties: 5% of gross revenue up to year 15 of COD; 15% from year 16
- Profit Tax: 15% on net profit (after depreciation) from year 6, following tax holiday of 5 years
- Dividend: 90% of total net profit after loan service and profit tax
- Annual Operation & Maintenance costs: Fixed O & M cost 1% of project base cost plus annual variable cost of 0.2$/MWh (2002 year price)
- Depreciation : 4% per annum (straight-line for 25 years) on fixed assets and
  20% per annum (straight-line for 5 years) on financing fees

5.3 RESULTS OF ANALYSIS FOR BASE CASE SCENARIO

The total project cost and the financing plan for base case scenario are summarized below:

Cost Item		
Base cost	343.7 M$	(90.5%)
Financing fees	5.5 M$	(1.4%)
IDC	28.7 M$	(7.6%)
Initial WC	1.8 M$	(0.5%)
Total project cost	379.6 M$	(100.0%)

Financing Plan		
Equity capital	113.7 M$	(30%)
Loan capital	265.9 M$	(70%)
Total capital	379.6 M$	(100%)

EIRR of the Project is estimated at 19.5% which is considered acceptable. This exceeds largely the opportunity cost of capital of 10% and ADB's criterion of 12%. This means Nam Ngiep I is worthwhile to be implemented from the view-point of Lao PDR economy as a while.

Financial analysis indicates FIRR is estimated at 13.1%, ROE (Return on Equity) at 16.3% and the minimum DSCR (Debt Service Cover Ratio) is 1.4. Since all the three financial indicators are well above generally acceptable values, the Project is considered to be viable as BOT scheme.

5.4 SENSITIVITY ANALYSIS

A sensitivity analysis has been carried out under four adverse scenarios conceivable as shown below:

Scenario	Risk Case	Cause and Effect
Case 1	half--year construction time overrun	which results in half-year delay in commissioning
Case 2	10% increase in capital cost	which results from increase in work quantity, increased costs of materials, additional works, etc
Case 3	10% reduction in tariff	which results from unexpected low tariff caused by low pool prices
Case 4	20% drop in power output for first 3 years	which results from very dry hydrological conditions hitting the first three years of operation, which causes reduced water flows

As indicated in the following table, the Project remain still viable under all such adverse conditions although some cases result in marginal values of FIRR and ROE. Cases of 10% increase in capital cost in 10% reduction in tariff are most sensitive to the profitability of the Project.

No.	Scenario	FIRR (%)	Si[a]	EIRR (%)	SI[a]	ROE (%)	DSCR
Base Case	Normal operation	13.1	-	19.5	-	16.3	1.4
Case-1	Half-year construction time overrun	12.6	0.5	17.9	0.8	14.7	1.3
Case-2	10% increase in capital cost	11.9	0.9	17.7	0.9	14.5	1.3
Case-3	10% reduction in tariff	11.8	1.0	17.6	1.0	14.3	1.3
Case-4	20% drop in power output for first 3 yea	12.2	-	18.9	-	14.8	1.1

[a] SI (Sensitivity indicator) is a ratio of percent change in FIRR or EIRR to percent change in sensitivity parameters.

5.5 RISK ANALYSIS

The project involves risk for all parties (GoL, developer, power purchaser, contractors, lenders, etc). The risk can be categorized depending on the project development stages and types of risks as shown in the following table. Mitigation of those risks, or transfer of them to parties best suited to bear them is essential to attain successful project implementation.

Major risks can be shared among major risk takers of GoL, developer and contractor/operator. Political or country risks or force majeure risks can be usually guaranteed by GoL and some of them are required to be insured by multilateral agencies like MIGA, World Bank, etc to satisfy lenders.

Successful mitigation of the risks of commercial, political, and nonpolitical or force majeure events is critical to a project's financial feasibility. Various agreements, contracts, and insurance measures associated with the project are designed to maximize risk mitigation.

The risk allocation matrix shown below is produced on the basis of the principle of "allocate risks to who can best manage them" as a tool fo analyze the extent of mitigation and the residual risk for prospective investors.

The residual risks which the project company or lenders eventually should assume are market risk and financial risk (inflation, charge in exchange rate, change in interest rate). These residual risks together with financial profits expected will determine investor interest in participation in the project.

Project Risk Analysis			Risk Taker							
Stage	Type of Risks	Cause of Risk and/or Consequence of Risk Occurrence	GoL	Developer	Power purchaser	EPC Contractor	Operator	Insurance Co.	Project Company	Lenders
Pre-operation	Investment risk	Equity non-payment	O	O						
	Planning risk	Land not acquired	O							
		Local people opposition	O	X						
		Adverse geology	X	O						
		Adverse hydrology (flooding & drought)	X	O						
	Construction risk	Design defects				O				
		Cost overrun		X		O				
		Time overrun		X		O				
		Incompletion		X		O				
		Damage to third-party						O		
Operation	Operation risk	Poor operation & maintenance					O			
		Decline in power output (due to low waterflow)							O	O
		Transmission line fault					O			
	Market Risk	Offtaker nonpayment			O			X		
		Decline in power output (due to low demand)							O	O
		Reduction in power tariff							O	O
	Financial risk	Inflation							O	O
		Change in exchange rate							O	O
		Change in interest rate							O	O
Common	Environment risk	Adverse effects on environments		O				O		
	Force majeure	Natural disaster and calamities	O	X				O		
	Political risk	Expropriation, no-repatriation/remittance	O					O		

(Note) "O"denotes main risk taker and "X", supporter to main risk taker.